NON-PUBLIC?: N
ACCESSION #: 8807060422

LICENSEE EVENT REPORT (LER)

FACILITY NAME: Sequoyah, Unit 2 PAGE: 1 of 8

DOCKET NUMBER: 05000328

TITLE: Two Reactor Trips During Unit Startup Resulting From Steam Generator Lo-Lo Level Which Were Caused By Feedwater Flow Perturbations
EVENT DATE: 06/08/88 LER #: 88-028-00 REPORT DATE: 06/30/88

OPERATING MODE: 1 POWER LEVEL: 015

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION
50.73(a)(2)(iv)

LICENSEE CONTACT FOR THIS LER:
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SUPPLEMENTAL REPORT EXPECTED: No

ABSTRACT: This report details two reactor trips, one on June 8 and one on June 9, 1988. Both trips occurred immediately after startup during power ascension and were a result of steam generator (S/G) No. 2 Lo-Lo level.
On the June 8, 1988 event, the plant was at approximately 15 percent power and was in the process of changing over to automatic speed control on the "A" main feedwater pump (MFP). The MFP speed controller was placed into automatic but S/G levels were dropping, and the MFP ran back to minimum speed. The speed controller was then placed back in manual to increase pump speed, and the S/G levels began to overfill. The main regulating valves were manually being closed to prevent overfill when a turbine trip/feedwater isolation occurred from a High-High level (75 percent) in S/G No. 4. The MFP was reset to reestablish main feedwater (MFW) flow, but before the pump could start, the reactor tripped on Lo-Lo level in S/G No. 2.
On the June 9, 1988 event, the plant was at approximately 19.7 percent power and was experiencing gland sealing steam pressure fluctuations because of inoperable pressure control valves. Because of the sealing steam pressure increasing to the No. 7 heater drain tank, the low pressure heater strings began isolating on high level conditions. The cycling of the heater isolation valves caused feedwater flow and S/G level perturbations. The unit operator attempted to maintain control of the S/G levels but the reactor tripped on S/G No. 2 Lo-Lo level.
The major causes of the events were insufficient attention to secondary side

maintenance and insufficient guidelines for MFW control during startup. To help prevent recurrence, a work control center has been established to maintain a more comprehensive control of outstanding work orders and additional guidelines for controlling S/G level during startup have been placed in operating procedures.

(End of Abstract)

DESCRIPTION OF EVENT

This report details two unit 2 reactor trip events, one on June 8 (from approximately 15 percent power) and one on June 9, 1988 (from approximately 19.7 percent power). Both trips occurred immediately after startup of the unit and during an increase in power. Details of each event are as follows.

June 8, 1988

On June 8, 1988, with unit 2 in mode 1 (15 percent power, 2235 psig, 554 degrees F), a reactor trip occurred at approximately 1319 EDT. The trip was a result of Lo-Lo level (18 percent) in steam generator (S/G) No. 2.

Before the trip, the following operational conditions existed:

1. Control rods (EIIS Code CD) were in manual control.

2. "B" main feedwater pump (MFP) (EIIS Code SJ) was shut down with high pressure steam isolated to the governor valves because of steam leak through on the valves.

3. "A" MFP was in manual speed control and being placed into automatic.

4. The "A" MFP r
circulation valve 2-FCV-3-70 was being manipulated manually to control MFP discharge pressure.

5. The main feedwater (MFW) bypass regulating valves were in automatic control.

6. The MFW main regulating valves were being controlled manually.

At approximately 1300 EDT in the process of changing over to automatic speed control on the "A" MFP, the recirculation valve (2-FCV-3-70) was manipulated to the closed position. The MFW bypass regulating valves were full open to control steam generator levels. Because the steam generator levels were decreasing, the unit operator (UO) opened the MFW main regulating valves to approximately 15 percent. At this time, the MFP speed controller indicator was in the approximate sync position, indicating that the controller inputs (pump discharge pressure and main steam header pressure) were stabilized. The speed controller was then placed in the automatic position to control the delta-pressure between the MFW pump discharge and the main steam header (EIIS Code SB). The S/G levels continued to drop, and the MFP decelerated to minimum speed (approximately 3000 rpm). The UO then returned the speed controller to manual and accelerated the MFP speed up to approximately 3600 rpm, but the S/G levels began to rise to the point of approaching the high level setpoint (60 percent). To curtail the overfill condition, the UO initiated manual closure of the MFW main regulating valves. The main regulating valves on loops 1 and 2 were closed, but during the

process of closing the valves on loops 3 and 4, a turbine trip/feedwater isolation occurred from a High-High level (75 percent) condition in S/G No. 4. In order to return feedwater to operation, an attempt was made to reset the MFP turbine governor valves. However, because the "A" MFP governor valves had not yet traveled to full closed position, the valves could not be reset and the "A" MFP could not be restarted. Immediately, the "B" MFP was reset, and the governor valves were opened, but the "B" MFP would not start because of the high pressure steam being isolated. At this point, the "A" MFP governor valves had traveled to the full closed position and could be reset. The "A" MFP low pressure governor valve had reached approximately 75 percent open position when the reactor tripped on Lo-Lo level (18 percent) in S/G No. 2.

Subsequent to the trip, the reactor coolant system (RCS) average temperature (Tavg) decreased to approximately 510 degrees F on loop 1 and approximately 520 degrees F on the other three loops. The lower temperature on loop 1 was a result of the auxiliary feedwater (AFW) (EIIS Code BA) turbine-driven pump being supplied from this loop. A feedwater isolation also occurred as designed on a reactor trip coincident with low Tavg of 554 degrees F. Pressurizer pressure decreased to approximately 2080 psig, and pressurizer level decreased to approximately 10-percent level. Letdown isolation occurred as designed at 17 percent pressurizer level to maintain RCS inventory.

June 9, 1988

On June 9, 1988, with unit 2 in mode 1 (19.7 percent power, 2240 psig, 558 degrees F), a reactor trip occurred at approximately 0512 EDT. The trip was a result of Lo-Lo level (18 percent) in S/G No. 2.

Before the trip, the following operational conditions existed:

1. "B" MFP was shut down with steam isolated as on the June 8, 1988 event.

2. "A" MFP was operating in manual speed control.

3. "A" MFP bypass regulating valves were in automatic control and the main regulating valves were in manual control, approximately 20 percent open.

4. S/G levels were being controlled at approximately 45 percent.

The unit was experiencing turbine gland sealing steam pressure fluctuations. The high pressure (HP) turbine sealing steam header pressure and the spillover sealing steam pressure to No. 7 heater drain tank (HDT) (EIIS Code SM) were being controlled manually from the Turbine Building (TB) (EIIS Code NM) using sealing steam supply bypass valve 2-PCV-47-181 and the spillover bypass valve 2-PCV-47-191. The bypass valves were being used because the main pressure regulating valves 2-PCV-47-183 and 2-PCV-47-193 for these flow paths were not operating correctly. The sealing steam supply bypass valve 2-PCV-47-181 was

being controlled manually using the valve handwheel because the valve did not respond to the handswitch from the main control room (MCR). This valve was being continuously throttled down to maintain the sealing steam header pressure (desired pressure of 140 psig). The No. 6 low pressure (LP) heaters abnormal level alarm was received in the MCR on heater B-6. Two additional AUOs were immediately dispatched to the TB to assist in manipulating the pressure control valves because of the sealing steam pressure continually increasing. The "A" and "B" LP heaters isolation valves began isolating because of high level conditions in the heaters. An additional operator was immediately directed by the unit 2 assistant shift operations supervisor (ASOS) to operate the heater controls. The heaters isolation valves were reopened from the MCR but continually reclosed because of the high level condition still present in the LP heaters. The heater string isolation valves cycled several times causing a perturbation in the "A" MFP discharge pressure and subsequent perturbation in the MFW flows and S/G levels. The UO operating the feedwater controls, changed over to manual control of the MFW bypass regulating valves and attempted to maintain S/G levels by manually controlling the "A" MFP speed, the MFW main regulating valves, and the MFW bypass regulating valves simultaneously on all four S/Gs. The S/G level perturbations could not be curtailed, and the S/G No. 2 level dropped to the Lo-Lo level setpoint (18 percent) initiating the reactor trip. The other three S/G levels also dropped to between 10-20 percent, but S/G No. 2 was the first to drop below the Lo-Lo level setpoint.

Subsequent to the trip, RCS Tavg decreased to approximately 510 degrees F on loop 1 and approximately 520 degrees F on the other three loops. The lower temperature on loop 1 was a result of the AFW turbine-driven pump being supplied from this loop. Feedwater isolation also occurred at low Tavg (554 degrees F) coincident with the reactor trip. Pressurizer pressure decreased to approximately 2070 psig, and pressurizer level dropped to approximately 10 percent level. Letdown isolation occurred as designed at 17 percent pressurizer level.

After each of the reactor trips detailed in this report, Operations personnel responded to safely recover the unit from the transients using emergency procedures E-O, "Reactor Trip or Safety Injection," and ES-0.1, "Reactor Trip Response."

CAUSE OF EVENT

June 8, 1988

The immediate cause of the reactor trip on June 8, 1988, was a Lo-Lo level in steam generator No. 2. The Lo-Lo level condition was caused by perturbations in the feedwater flow and steam generator levels while attempting to convert from manual to automatic control of the "A" MFP during power ascension. Contributing causes to the feedwater perturbations were as follows:

1. The UO manipulating the MFW controls had been trained on the plant simulator for unit startup but was limited in actual plant startup experience.

2. Management resource controls did not provide for a sufficient number of experienced operators to allow dedicated coaching of the UO during this startup even though the UO's experience in this task was limited to training on the simulator.

3. The plant simulator controls for feedwater do not model the actual plant accurately in that the controls on the simulator are very stable even at low power levels when changing over to automatic speed control.

4. High pressure steam was isolated to the "B" MFP because of steam leaks through the governor valves. This caused additional delay in returning feedwater to operation after the feedwater isolation.

June 9, 1988

The immediate cause of the reactor trip on June 9, 1988, was a Lo-Lo level in steam generator No. 2. The Lo-Lo level condition was a result of MFW perturbations caused by the LP heaters isolating. The LP heaters were isolating because of high level conditions in the heaters which was caused by gland sealing steam pressure increasing and pressurizing the No. 7 HDT where the LP heaters' condensate drains. Contributing causes to the gland sealing pressure fluctuations and subsequent reactor trip are as follows:

1. Approximately 20 outstanding work requests (WRs) were still open because of previously identified problems on various secondary plant equipment (main steam, feedwater, heater drains and vents, and turbine electrohydraulic controls). Some of these resulted in operators having to use alternate methods (manual) to control various critical secondary side parameters.

2. The TB operators were attempting to control gland sealing steam pressure manually via the bypass pressure regulating valves 2-FCV-47-181 and -191.

3. During a subsequent investigation, it was discovered that the sealing steam supply bypass valve 2-PCV-47-181 had been supplied incorrectly on the original Westinghouse contract and had been modified in 1972 to meet the actual system parameters. The original valve was rated for 150 psig at 500 degrees F, but was used in an approximate 1100 psig, 550 degrees F application. After the valve was supplied to TVA, Westinghouse (valve supplier) and Leslie Controls Corporation (valve manufacturer) modified the valve to allow use in the higher pressure application. During the modification, a stronger valve stem and spring pack were installed and the torque switch thrust setting was changed from the original 123-lb setting to 7500-lb setting required for the higher steam pressure. Westinghouse

subsequently notified the industry of this problem in September 1976 via "Availability Improvement Bulletin No. 7606." However, Limitorque Corporation (valve actuator manufacturer) records were not revised and, up until the time of this event, still showed a thrust setting of 123 lbs. When the valve was last tested on April 21, 1988, using the motor-operated valve analysis test system (MOVATS), the Electrical Maintenance section contacted Limitorque Corporation to obtain the correct torque switch setting. Since the Limitorque Corporation records still showed a setting of 123 lbs, this value was used to set the torque switch. Therefore, during this event, when the valve was called upon to close against system pressure, the torque switch would open prematurely and prevent the valve from closing. This prevented the valve from controlling sealing steam pressure automatically.

ANALYSIS OF EVENT

Both events detailed in this report (June 8 and June 9, 1988) are being reported in accordance with 10 CFR 50.73, paragraph a.2.iv, as automatic actuations of the engineered safety features actuation system (ESFAS) and reactor protection system (RPS).

On both events, the safety-related reactor protection system (RPS) logic
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rformed as designed to mitigate the consequences of the S/G Lo-Lo level condition by causing a reactor trip (reactor trip breakers opened and all control rods dropped to bottom position). If an actual postulated safety analysis accident had occurred to cause the S/G Lo-Lo level condition, the reactor would have shut down as designed. Therefore, neither of the events detailed in this report caused the safety of the plant or public to be compromised.

CORRECTIVE ACTIONS

Immediate corrective actions on both events were to bring the plant to stabilized conditions using Emergency Procedures E-O, "Reactor Trip or Safety Injection," and ES-0.1, "Reactor Trip Response." Additional corrective actions for each event are described as follows:

June 8, 1988

1. Administrative Instruction (AI)-30, Nuclear Plant Conduct of Operations," was revised on June 18, 1988, to clarify the responsibilities of the shift Operations supervisor (SOS), assistant shift operations supervisor (ASOS), and the unit operator (UO). This revision identified the responsibilities of the ASOS as supervising the startup and providing coaching as necessary. The ASOS also has the responsibility of identifying the need for additional help and requesting the SOS to provide additional personnel as necessary.

June 9, 1988

1. Various secondary side plant WRs were worked to repair equipment which could adversely affect plant startup or operation. Specifically, the WRs potentially related to this event are as follows:

a. 2-PCV-47-183 (sealing steam supply main pressure regulating valve) was not responding correctly. Valve was repaired under WR B288067.

b. 2-PCV-47-193 (sealing steam spillover main pressure regulating valve) was not controlling pressure correctly. Valve was repaired under WR B267642.

c. 2-LS-6-177 (No. 6C LP heater level switch) was nonfunctional. Switch was repaired under WR B759554.

d. 2-PCV-47-180 (sealing steam supply isolation valve) had a packing leak. Valve was repaired under WR B785238.

e. 2-PCV-47-189 (sealing steam supply to HP turbine pressure control valve) not controlling pressure correctly. Valve was repaired under WR B299832.

2. The sealing steam supply bypass pressure control valve, 2-PCV-47-181, was repaired and the torque switch reset to the correct value of 7500 lbs. under WR B751299. A documentation only Design Change Notice (DCN) will be issued by July 22, 1988, to update the TVA design drawings with the correct thrust setting.

To return the "B" MFP to service after both events, the "B" MFP high pressure governor valve (2-FCV-1-44) was repaired on June 17, 1988, to stop the steam leak through under Work Request (WR) B751430.

To help reduce the MFW perturbations experienced in both of these events, General Operating Instruction (GOI)-2, "Plant Startup from Hot Standby to Minimum Load," was revised on June 16, 1988, to give additional guidelines for controlling S/G levels during startup. These guidelines are also now being used in the simulator training to ensure the simulator MFW controls more closely model actual plant MFW parameters during startup. This administrative control will maintain consistency between the simulator and actual plant MFW responses.

Also, to reduce the backlog of secondary plant maintenance problems and to gain better control of overall plant status, a work control center has been established for unit 2. Before these events, the work center was established for unit 1 but not complete on unit 2. Use of the work control center allows for a comprehensive review of plant work activities and equipment conditions. The SOS and ASOS for each unit are required to review outstanding work orders in the work control center before each shift. More information on this effort will be detailed in an NRC licensing submittal at a later date.

ADDITIONAL INFORMATION

The reactor trips detailed in this report are the fourth (June 8) and fifth (June 9) reactor trips since unit 2 startup from an extended shutdown of approximately 2 1/2 years (August 85-May 88). The first three reactor trips are detailed in LERs SQRO-50-328/88023, 88024, and 88027. The major causes of the first three reactor trips were equipment failure, procedural noncompliance, and equipment manufacturing defect, respectively.

COMMITMENTS

A documentation only DCN will be issued by July 22, 1988, to update design drawings with the correct thrust setting for 1-, 2-PCV-47-181 (DNE-MEB).

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ATTACHMENT # 1 TO ANO # 8807060422 PAGE: 1 of 1

Sequoyah Nuclear Plant
Post Office Box 2000
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June 30, 1988

U. S. Nuclear Regulatory Commission
Document Control Desk
Washington, DC 20555

Gentlemen:

TENNESSEE VALLEY AUTHORITY - SEQUOYAH NUCLEAR PLANT UNIT 2 - DOCKET NO.
50-328 - FACILITY OPERATING LICENSE DPR-79 - REPORTABLE OCCURRENCE REPORT
SQRO-50-328/88028

The enclosed licensee event report provides details concerning two unit 2 reactor trips resulting from steam generator Lo-Lo level during unit startup which were caused by feedwater flow perturbations. This event is reported in accordance with 10 CFR 50.73, paragraph a.2.iv.

Very truly yours,

TENNESSEE VALLEY AUTHORITY

/s/ S. J. SMITH
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Plant Manager

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